

Economic viability of small nuclear reactors in future European cogeneration markets

Johan Carlsson^{a,*}, David E. Shropshire^a, Alik van Heek^b, Michael A. Fütterer^a

^a European Commission, Joint Research Centre, Institute for Energy and Transport, P.O. Box 2, NL-1755ZG Petten, The Netherlands

^b NRG, P.O. Box 25, NL-1755ZG Petten, The Netherlands

ARTICLE INFO

Article history:

Received 5 November 2011

Accepted 10 January 2012

Available online 27 January 2012

Keywords:

Small medium reactor
Combined heat and power
Nuclear economics

ABSTRACT

Small nuclear reactors align well with the small heat-capacity needs for many European process industries. Combined heat and power (CHP) reactors can support the EU low-carbon society goals while providing stability in production and cost. High temperature reactor technologies are well suited for the production of “high value” heat by producing temperatures of 200–550 °C. However, little is known about the market potential or economic competitiveness of these reactors in future European cogeneration markets. This study shows that the greatest potential is in chemical/petroleum, paper, metal, and bioenergy markets with small capacities (50–250 MWth). Target market costs for coal-CHP and natural gas-CHP were determined to range from 60–100 €/MWh and 95–208 €/MWh, respectively. Costs for “heat-only” ranges from 30–60 €/MWh based on gas boilers. Parametric analysis was used to create a cost breakdown (capital, operations and maintenance, fuel, and decommissioning) for an equivalent nuclear CHP that could compete against coal-CHP and natural gas-CHP. Sensitivity analysis showed that reactor capital costs and the costs of capital had the largest influence on competitiveness. In summary, the opportunities for nuclear CHP are highest in natural gas-CHP markets; however the benefits for CO₂ reduction were greatest against coal-CHP.

© 2012 Elsevier Ltd. All rights reserved.

1. Introduction

The European Union (EU) is tackling the challenge of how to make low-carbon technologies affordable and competitive through its Sustainable Energy Technology Plan (EC, 2007). Cogeneration goals are in-line with EU plans for a Low-Carbon Society, particularly energy efficiency. Several EC Directives support these goals including: Cogeneration Directive (EC, 2004) which promotes energy efficiency in electricity and heat production, Energy End-use Efficiency and Energy Services Directive (EC, 2006) promotes energy efficiency in residential and industrial sectors, and the recast of Energy Performance of Buildings (EC, 2003) obliges constructors to consider district heating and cooling for new and refurbished larger public buildings.

Abbreviations: CCGT, Combined Cycle Gas Turbine; CCS, Carbon Capture and Storage; CHP, Combined heat and power; COA, Code Of Accounts; D&D, Decontamination and Decommissioning; FBC, Fluidized Bed Combustion; HTR, High temperature reactor; IGCC, Integrated Gasification Combined Cycle; LCOE, Levelised Cost of Electricity; LWR, light water reactor; NOAK, Nth Of A Kind; NPP, Nuclear power plant; RES, Renewable energy systems; SMR, Small and medium-sized reactors; VHTR, Very high temperature reactor

* Corresponding author. Tel.: +31 224 565341.

E-mail address: johan.carlsson@jrc.nl (J. Carlsson).

The Directives mentioned above are general, so nuclear is not mentioned specifically. However, nuclear technologies are identified in the EUROPAIRS (2009) project of the EU Seventh Framework Programme (FP7) for application to European cogeneration markets. In EUROPAIRS, boundary conditions for the viability of nuclear cogeneration systems connected to conventional industrial processes were investigated. The purpose was to develop a demonstrator reactor coupling a very high temperature reactor (VHTR) with industrial processes. The project aimed to understand the technical, industrial, economical, licensing, and safety requirements for the nuclear system and the end user process, as well as the coupling system.

Due to the sheer size of the heat market in Europe the potential for nuclear cogeneration is very large. The industrial heat market was 8.7 EJ in 2005 of which the largest share (~43%) is for high temperatures, i.e., above 400 °C (EUROHEATCOOL, 2006). This value corresponds to a permanently installed power capacity of approximately 120 GWth, which is consistent with recent findings from the EUROPAIRS project (Bredimas, 2010). Demands in the low (< 100 °C) and medium temperature ranges (100–400 °C) attract a smaller (although still considerable) share, of about 30% each. Heat demand structures internationally are expected to be similar to these results.

Small nuclear cogenerating reactors may be suited to support existing process heat markets since their smaller sizes align well

with the capacity requirements of process industries. Recently, there has been a renewed interest in small and medium-sized reactors (SMR) due to their low carbon generation, simpler design, more affordable economics, job creation, and possibility for new international market opportunities. These concepts are being pursued to support small utilities, countries with financing or infrastructure constraints, distributed power markets, and process heat customers. SMR designs developed some decades ago were not successful since the economy of size was the prevailing approach for nuclear power production. In a future energy mix with more small scale and intermittent production from renewable energy systems (RES), SMRs have the potential to become an important player. SMRs may be better suited for the flexible operation needed to balance RES variability.

Studies have looked at the economic potential for SMRs to compete in electricity markets in Europe (Shropshire, 2011). This study suggests that SMRs may effectively compete in future electricity markets if their capital costs are controlled, favorable financing is obtained, faster construction with lower uncertainties can be achieved (lower risk perception by banks), and reactor capacity factors match those of current light water reactors.

Candeli et al. (1988) evaluated the market potential of small and medium-size nuclear reactors as combined heat and power plants in specific applications in Europe. Early studies concluded that the market potential was promising, but that the potential varied between Member states. The heterogeneity of the European market was seen as a difficulty to be overcome.

There are about a dozen high temperature reactor (HTR) concepts which have been advanced by Japan, Russia, US, Netherlands, South Africa, China, and France. The most current concept is the Chinese HTR-PM which is due to be deployed around 2013 (Zhang, 2007, 2009). Paper studies were conducted by NRG on small HTR designs, including the ACACIA and (earlier) INCOGEN nuclear cogeneration concepts (van Heek, 2004).

Full data needed for economic analysis or market assessment is not publicly available yet for small nuclear cogenerating reactors. However, plant economics will inevitably be a key determinate of their viability, which is the focus of this paper. In Section 2, ranges of market opportunities for small reactors are proposed; Section 3 presents the representative cogeneration markets; the target cost and modeling methodology are provided in Section 4; and Section 5 presents the target costs for each market investigated. Section 6 continues with a cost sensitivity analysis while Section 7 includes a discussion of challenges for cogeneration. Section 8 describes future studies, and the conclusions are presented in Section 9.

2. Market opportunities

The purpose of this study is to develop “target cost” estimates for a range of competitive cogeneration market opportunities, competing against coal and natural gas combined heat and power systems. Renewable energy systems were not targeted for competition since they are subsidized by energy policy to achieve set market shares. Target markets are based on projected 2030 energy technology costs; allowance of this timeframe provides adequate time for small reactors currently in concept phase for design, licensing, and deployment. The costs for all systems reflect Nth-Of-A-Kind (NOAK)¹ systems and are in constant year 2005 Euros.

The heat demand over a range of temperatures for various European industries is presented in Fig. 1. About 60% of the heat

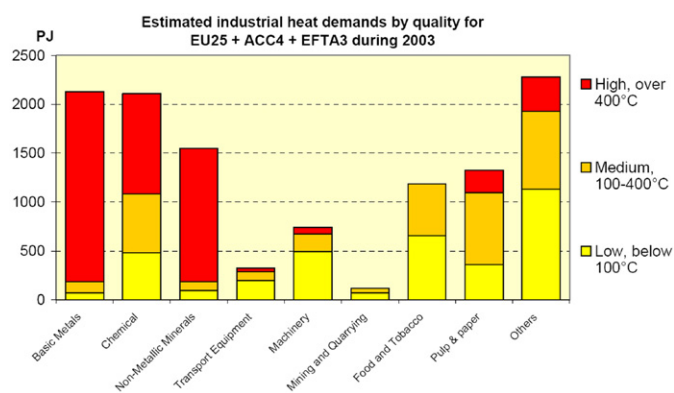


Fig. 1. Industrial heat demands estimated by temperature and manufacturing branch for 32 countries (EU27 + EFTA + Croatia + Turkey) in Europe. The figure is based on experience from the German industry reported in (AGFW, 2005) and applied on an IEA database for the target area (EUROHEATCOOL, 2006).

demand is for low (< 100 °C) to moderate temperatures (100–400 °C). The processes with the highest temperature demands can be found in the basic metal, chemical (both heat supply and as feedstock), and non-metallic minerals branches.

EUROPAIRS extended this analysis by providing estimates of industrial heat demands beyond 400 °C. Heat consumption between 500 and 1000 °C is relatively lower, but above 1000 °C there is a strong heat demand of about 30% across various industries (e.g., cement, steel, and glass industry). In 2010 about 30% of the heat demand for industrial applications in Europe was provided by cogeneration plants, and the remainder by boilers and burners (Bredimas, 2010). Existing fossil powered cogeneration plants, the so called “plug-in market” are the most similar to nuclear cogeneration plants, because they are usually of larger size and provide heat to industrial processes requiring a more constant demand. These older fossil-based CHP plants could find future roles as economic cold or hot back-up plants after being replaced by less-carbon intensive units.

EUROPAIRS also estimated that the average thermal capacity demand per site is 34 MWth for the existing cogeneration plug-in market and 66 MWth for the potential cogeneration market in Europe, which for now is served mainly by natural gas fueled boilers. These same sites usually also consume large amounts of electricity so that CHP does make sense. Fig. 2 shows the average site thermal capacity by sector and market.

From Fig. 2 it can be seen that many industries require relatively small heat sources. Nevertheless, due to the large size of the European heat market the sites demanding more than 100 MWth sum up to a large sector consisting of about 87 GWth. The steam and heat demand of industries vary greatly in terms of temperatures and mass flows for different industrial processes. Often heat and steam are extracted from the same heat source at different temperatures and pressures, and are transported to various locations in a factory to support process heat applications. Additionally, a single cogeneration plant often provides heat for several heat users with different demands at the same site. The requirements for nuclear cogeneration were derived from the industrial sector and market data. Relatively small sized reactors (from 50 to 250 MWth) with reactor technologies capable of supporting processes in the range of 200–550 °C were selected as appropriate candidates to support the various market niches. Examples of industries with suitable characteristics for nuclear cogeneration include the following:

1. The chemical industry which produces many types of end products. This industry runs numerous processes that require a wide range of temperatures. Often chemical companies are

¹ NOAK is the cost for construction of a mature technology. Extra costs related to First-Of-A-Kind plants can be neglected.

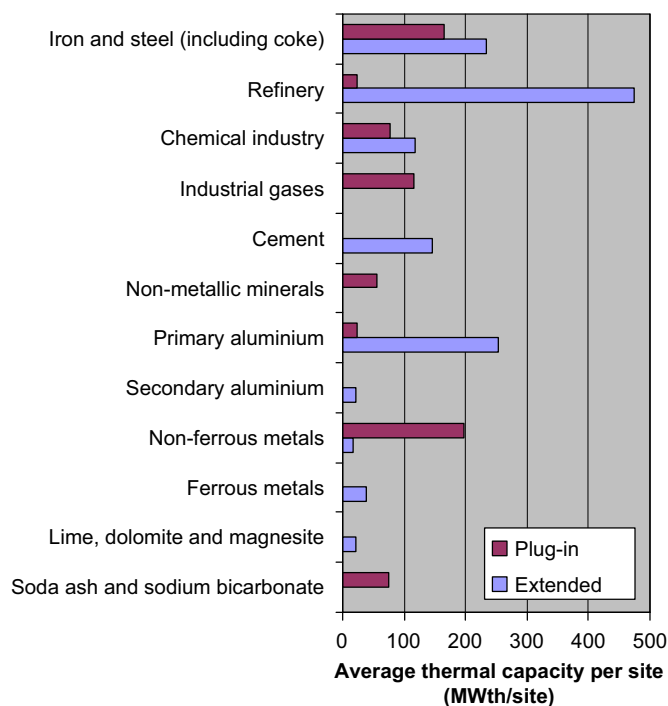


Fig. 2. Average site thermal capacity by sector and market (Bredimas, 2010).

located in big clusters and typically use fossil fueled cogeneration for part of their heat supply. Naphtha cracking and ethylene production are two very energy intensive processes that appear suitable for nuclear cogeneration.

2. Refineries consume large amounts of heat and steam. Most of their processes require temperatures below 550 °C (except hydrogen production by steam methane reforming). Today they primarily use oil and gas for heat and electricity production. Up to 10% of the energy comes from off gas recovery of chemical byproducts. Heat production not provided through recycling currently comes from fossil cogeneration plants, but could be provided by carbon-free nuclear cogeneration.
3. Biomass drying and torrefaction requires temperatures in the range of 200–300 °C. The torrefied product can either be co-fired with coal or used to produce synthetic transportation fuel. This is an attractive option since torrefaction can reduce biomass transport and greenhouse gas emissions. The temperature range is well suited for nuclear cogeneration.

Nuclear cogeneration, similar to nuclear power in general, requires a large upfront capital investment making it suitable for industries with continuous and high heat demand. Alternatively, hybrid nuclear cogeneration plants that can switch between heat and power production to maintain high load factors could be ideal. However, the authors reserve this topic to a separate paper. The authors also recognize that there is a potential market for larger reactors which could support multiple process users simultaneously and in very high temperature applications, such as for certain hydrogen production methods. However, given the R&D status of these applications, they go beyond this study's time scope of 2030.

2.1. Thermal efficiency changes from using CHP

When converting a fossil fired power production plant into a cogeneration plant the total thermal efficiency of the plant significantly increases from about 30–50% to 80–90% depending on the plant type. This comes at a loss of electrical efficiency of

Table 1

Technical thermal peak load data on CCGT, Condensing Coal CHP, and Cogen HTR plants (CASES, 2008; EC, 2008).

Key parameters	Units	CCGT CHP	Condensing coal CHP	Cogen HTR
Electrical efficiency	%	47	37	30.1
Thermal efficiency	%	42	51	39.9
Load factor	%	75–85	75–85	75–85
Max. availability	%	90	95	95
CO ₂ emissions	kg/MWh	350	850	0
CO ₂ emissions w/CCS	kg/MWh	60	145	0

about 3–13%. For example, a typical Combined Cycle Gas Turbine (CCGT) plant operates at an electrical efficiency at electrical peak load of about 63% for pure electrical production but ~59% electrical efficiency for a CCGT CHP (CASES, 2008). Illustrative performance data at thermal peak load for the CCGT CHP, Integrated Gasification Combined Cycle (IGCC) CHP, and a representative cogenerating HTR are provided in Table 1.

2.2. Current and future CHP technologies+boiler

Natural gas industrial boilers or natural gas firing are the easiest way to produce heat in the form of steam up to 550 °C. Boilers typically have thermal efficiencies of about 89%. A boiler can be ramped up quickly and the low investment cost allows it to be switched on and off with only limited economic penalty. Operation and maintenance are also a little demanding.

Most CHP plants today use natural gas or coal as fuel. But, biomass and biogas have grown in importance in Europe, especially in Scandinavia and in the Baltic states. CHP plants achieving 10% more energy efficient production of heat and electricity compared to separate production are permitted to receive subsidies from national support schemes. Also CHP plants will receive some freely allocated emission allowances from the European Union Emission Trading System. Biomass fueled CHP receives the most financial support and free emission allowances since it is powered by a renewable fuel. Due to this fact the comparison will be made against fossil-fueled CHP plants.

CCGT plants and Fluidized Bed Combustion (FBC) are most commonly used today. In 2030 the state-of-the-art is assumed to be CCGT natural gas plants and IGCC coal plants, which is why they were chosen for this study. It is envisaged that CCS would be the reference plant at this time, possibly together with synthetic fuel production.

Carbon Capture and Storage (CCS) technology has been tested on smaller scale pilot plants of up to 40 MWth and there are full-scale plants planned or under construction. Potentially, CCS can curb CO₂ emissions by 90–95% at the expense of a typical drop in electrical efficiency of 5–6%. The additional costs for CCS range from 3–15 €/tCO₂ (CASES, 2008).

3. Representative cogeneration markets

Current state-of-the-art CHP plants for coal (IGCC) and natural gas (CCGT) were chosen to represent the competing market technologies in this study. They are used to define the overall cost range, in which nuclear cogeneration is expected to compete. Target market costs were determined for these fossil technologies with and without CCS. The range of target market costs are taken from the 2008 European Commission (EC) staff working document (EC, 2008) that were used in the second Strategic EU Energy

Table 2

Second Strategic EU Energy Review projection data used to define the SMR-CHP markets.

	2007	2020 Low	2020 High	2030 Low	2030 High
Natural gas (€/MWh)	21.5	25.8	43.9	27.5	51.2
Coal (€/MWh)	7.7	8.2	13.3	9.0	16.3
CO ₂ cost (€/ton eq. CO ₂)	21		41		47

Review (EC, 2008). From this source, the plant sizes, technology efficiencies, fuel price projections,² and CO₂ emission costs were collected.

CHP may entail from 15–30% energy savings compared to separate production of heat and power (OPET, 2007), but the CHP investment cost is higher than the investment cost of an equivalent power plant. The extra costs were derived from the total production cost ratio per kWe for CHP versus non-CHP technology in backpressure mode versions (CASES, 2008). The CCGT to CCGT CHP ratio was determined to be 1.54. If CCS is added the ratio increases to 1.89. Most of the increased total cost per kWe comes from the loss of electrical efficiency and the rest from increased capital costs. The cost ratio for IGCC and IGCC CHP was 1.23. Adding CCS would increase the ratio to 1.59. These ratios were then multiplied by the total production costs for the CCGT and IGCC plants (based on the second Strategic EU Energy Review data) to calculate the equivalent cost of electricity production for CCGT and IGCC in CHP mode.

The costs of carbon dioxide emissions have been taken into account for all investigated technologies using the projected prices of the EU ETS given in Table 2. The year 2030 was used for our analysis.

In the EU ETS, efficient cogeneration systems will be allocated 80% of their needed emission allowances for free until 2013. Thereafter the share of free allowances is reduced linearly by 1.74% per year (EC, 2004). A modification was made to the SEER-2 data to take into account the partially free allocation of emission rights that CHP receives.

It has been assumed that plants with CCS will also have to pay for the fraction of CO₂ they emit (ETSAP, 2010a). The estimated total cost for CCGT CHP and IGCC CHP systems, both with and without CCS, are given in Fig. 3.

Target cost ranges are identified for each market, i.e., coal (IGCC) CHP with and without CCS, and gas (CCGT) CHP with and without CCS. This range includes the lowest cost up to the value for the high fuel range (e.g., for Market #3, Gas CCGT CHP the targeted cost range is 95–180 €/MWh). The large span is mainly due to the large range of projected natural gas prices in 2030. For nuclear cogeneration to be competitive in the targeted markets with the other CHP technologies, the small reactor would need to produce a combination of heat and electricity. The primary users of the plant would utilize the process heat and at least a portion of the electrical production. Excess electricity would be sold in spot market auctions or at intraday markets. A further breakdown of these cost components is described in Section 2.1.

The four competitive ranges were chosen based on the competitive costs from fossil energy, but it does not include heavy oils often used in refineries since it is a limited market. Additionally, the costs for renewable energy were not directly compared, since they are subsidized to reach target shares within

the EU. The addition of CCS leads to higher costs and lower efficiencies. However the additional costs from carbon emissions are reduced, especially for coal because for a given heat output, coal produces almost twice as much CO₂ as natural gas.

The SMR cogeneration target markets defined in this study are described as follows:

- Market #1: Coal IGCC CHP, used in furnaces in the iron and steel industry.
- Market #2: Coal IGCC CHP plus CCS, supporting the iron and steel industry.
- Market #3: Gas CCGT CHP, used in the chemical industry for the production of basic organic and inorganic chemicals.
- Market #4: Gas CCGT CHP plus CCS, also supporting the chemical industry.

3.1. Market segmentation for heat and electricity

Competitive market costs for separate heat- and electricity-only products are shown in Fig. 4. An industrial natural gas boiler represents the current market alternative for heat production only. The heat-only values are based on the fuel cost range expected (SEER-2 data) for gas boilers from ETSAP (2010b). It is plausible that exploitation of shale gas reserves could alter these assumptions, by decreasing the cost for natural gas. This would lower their target cost range and reduce the competitive range for nuclear cogeneration.

The competitive costs for “electricity only” range substantially depending on the type of market and the competing energy technologies as per Shropshire (2011).

In a heat-only market, the competing technology costs are quite low (30–60 €/MWh), therefore for the CHP unit to remain competitive it must produce heat within this cost range, and then allocate any additional cost towards electricity. For example, if a nuclear cogeneration unit operating in Market #3 (see Fig. 3) sells heat at 50 €/MWh, then according to the power credit method (Gen IV, 2007) the additional production cost would be taxed on the electrical production. Which in this case ranges from 45–130 €/MWh (i.e., 95–50=45, 180–50=130). From Fig. 4, we see that this cost range would be the most competitive on the spot and intraday markets. A dedicated user of heat and electricity could obtain a discounted cost for the electricity, which means that surplus electricity would need to be sold at a higher price. However as this cost allocation is performed, the same competitiveness issues would apply to either the fossil CHP or the nuclear cogeneration system.

4. Target cost methodology and modeling

4.1. Cost structure and breakdown

The target cost methodology used in this study is very similar to the method used in Shropshire (2011) to derive the costs for small and medium sized reactors for electricity only markets in the EU.

In order to develop “target cost” estimates for SMRs competing in each market sector, a cost breakdown structure is needed. The cost structure contains all the costs for the lifetime of the reactor and provides the data at a sufficient level of detail to define useful comparative information (e.g., cost of capitalized equipment, number of reactor operators, annual uranium ore requirements). The cost breakdown structure chosen for this study was the Code Of Accounts (COA) developed by the Gen IV Economic Modeling Working Group (Gen IV, 2007). The COA provides a means for

² As a caution, any projection of future natural gas and coal prices is subject to many uncertainties. For example, if shale gas can be extracted at low cost then natural gas projections for 2030 may be too high. On the other hand if developing countries use large amounts of natural gas, the prices could exceed the high estimated costs for 2030.

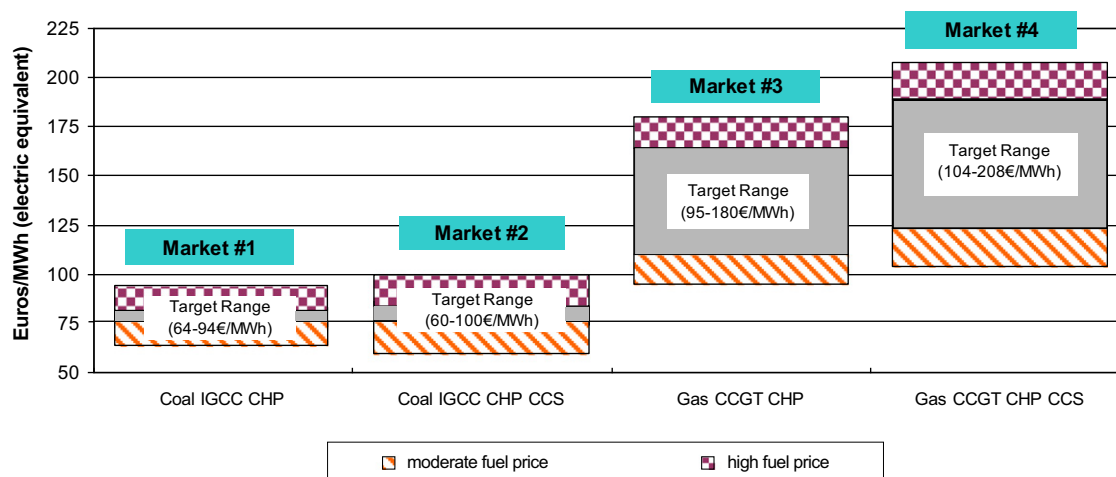


Fig. 3. Overall small reactor cost targets (without revenue from heat taken into account) to compete in CHP markets (2030).

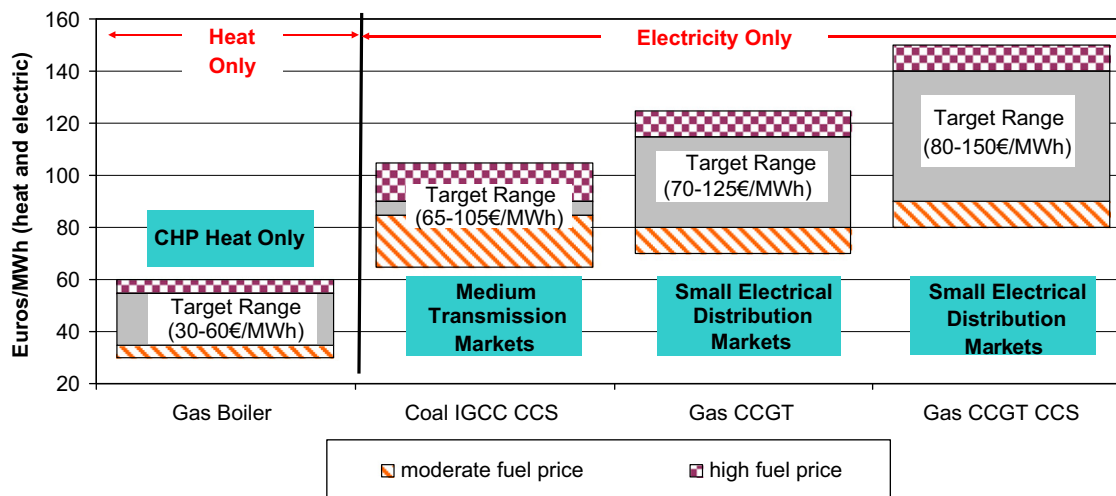


Fig. 4. Cost targets to compete in separate heat and electricity markets (2030).

consistently placing cost information in explicitly defined categories that are common to most SMR designs and their lifetimes. The COA contains capitalized costs that are incurred at the beginning of the project that must be financed. These costs are recovered in the price charged for electricity over the amortization life of the plant. The COA also includes annualized costs that are the recurring cash sums (e.g., operations and fuel costs) that are needed to sustain a constant level of annual production. The level of detail specified for this study is at the one and two-digit level. The one-digit level provides the highest level (least detail) cost breakdown for capital, operations, fuel cycle, and Decommissioning and Decommissioning (D&D) costs. The two-digit level provides additional details that are useful for describing resource requirements (e.g., equipment costs, staffing, Uranium ore costs, transportation, etc.). At this level of specificity, the subsystem categories are applicable regardless of the specific SMR technology.

4.2. Nominal reactor cost and performance, and financial inputs

The calculation of the “target cost” required the development of a cost breakdown for a representative (non-vendor design specific) nuclear reactor. In order to convert the leveled

Table 3

Relative average one-digit cost composition of LWR, SMR, and small reactor-CHP.

Summary costs	LWR (%)	SMR (%)	SMR-CHP (%)
Capital costs incl. financing	73	66	68
Operations and maintenance	16	19	18
Fuel cycle costs (incl. D&D)	11	15	14

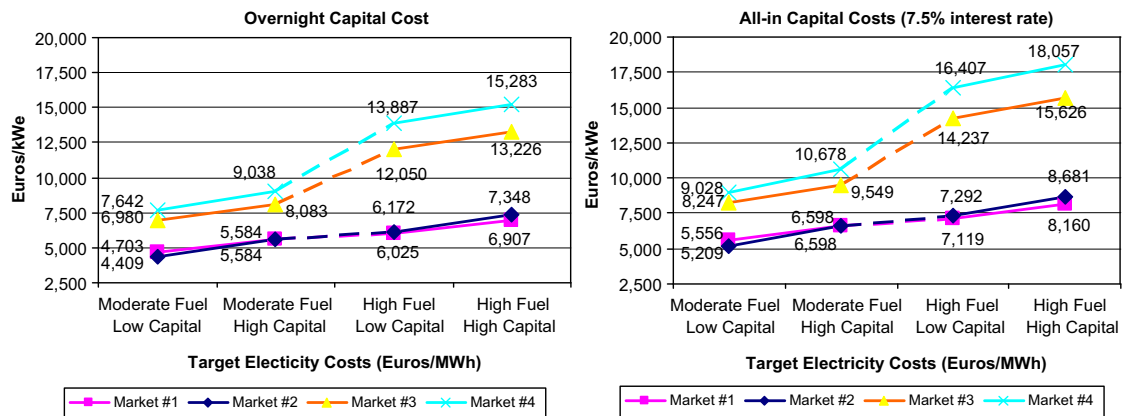
(electricity) cost targets into the two-digit cost breakdown, cost estimates for reactor designs were collected into a COA and then converted into percentages of the costs by cost category.

The process for determining these breakdowns was evolutionary. Initially the one-digit level cost breakdown for current LWR's was determined and then adjusted to account for differences for small reactors, and then the averages were adjusted for CHP HTR requirements. The average cost compositions for the LWR, SMR, and SMR-CHP are shown in Table 3. The LWR costs as derived from three LWR cost studies (MacDonald, 2010; Shropshire et al., 2009b; NERA, 2005; OECD/NEA, 2006) are shown in the far left column. These costs (normalized to €/MWh) include the total capital, annual operations and fuel cycle costs,

Table 4

Capital cost composition of the small reactor-CHP.

Summary costs	Small reactor-CHP average (%)	Examples of sub-accounts
10 Capitalized pre-construction	0.18	Land and land rights, site permits, plant licensing
20 Capitalized direct costs	57.00	Structures and improvements, reactor equipments, heat rejection system
30 Capitalized support services	17.00	Field indirect costs, construction supervision, commissioning
40 Capitalized operations costs	8.60	Staff recruitment and training, staff housing, staff salary related costs
50 Capitalized supplemental costs	3.22	Shipping and transportation costs, spare parts, taxes, insurances
10–50 contingency costs	14.00	Escalation, fees, interest during construction

**Fig. 5.** Target overnight capital and all-in capital costs by market sector.

and D&D sinking fund costs. The SMR cost breakdowns were derived from three SMR studies (NERA, 2005; US DOE, 2001; OECD/NEA, 1991) that are primarily based on LWR designs.

In comparison to the small reactor to the LWR average costs the small reactor would have a reduced share of the total costs due to capital and financing costs (66% vs. 73%). However, in absolute terms the levelized cost of electricity and the cost of capital per kWe would be much lower for the large reactor because of the dominance of the economy of size. Small reactor capital costs may still be competitive in niche markets due to their simplified designs, integrated power systems, economies of production, shorter construction schedules, savings in grid development, and ability to self-finance. The higher O&M costs (19% vs. 16%) reflect the necessity to have a minimum number of staff to meet human health, safety, and security needs. The higher open fuel cycle costs (15% vs. 11%) reflect more complex fuels with higher enrichments needed to support longer refueling cycles. However, near-term small reactor designs would use similar fuel enrichments as existing LWRs.³ The costs for a small reactor-CHP were further modified to account for approximately 10% higher capital costs for the CHP capabilities. All other costs were adjusted accordingly.

At the two-digit level, the capital cost breakdown was derived from the ACACIA CHP HTR concept (van Heek, 2004). The capital cost breakdown included all the capitalized expenses (pre-construction, direct costs, support services, operations, supplemental costs, and contingency costs). The derivation of these costs for the small reactor-CHP is provided in Table 4.

The two-digit operations and fuel cycle costs were based on the NOAK costs for a 1300 MWe ABB-CE System 80+™ Advanced Pressurized Water Reactor. The reactor performance and financial input parameters (capacity factors, efficiency, economic life, years

of construction, discount rates) were based on anticipated reactor performance of NOAK systems under moderate financial risk conditions.⁴ Sensitivity analysis was performed on these parameters to determine their effect on small reactor-CHP costs.

Since the primary costs were derived from an HTR design, the cost targets shown in Section 3 are most applicable for small reactors with similar HTR designs. The majority of SMR concepts are light water reactors, but advanced reactors also include high temperature reactors, fast neutron reactors, molten salt and heavy water reactors.

4.3. Target cost calculator

The cost breakdown structure was input to a spreadsheet that was used to back-calculate the detailed cost from the Levelized Cost of Electricity (LCOE) (e.g., 100 €/MWh). Additional details are also derived from the costs (e.g., overnight capital costs, equivalent number of staff). The detailed costs from the spreadsheet were subsequently input to Gen IV Economic Modeling Working Group (EMWG) MINI G4 ECONS model (Shropshire et al., 2009a) for further sensitivity analysis.

5. Target costs for each market

The target cost calculator was used to develop a cost range for each of the four markets described in Section 2. These target costs represent the reactor capital costs, operations, and the complete fuel cycle. All costs are provided on a combined cycle electricity-only equivalent basis. A heat credit is assumed based on the cost from an alternative technology, i.e., a natural gas boiler (30–60 €/MWh). The results from this analysis are provided in Figs. 5–7. For

³ Fuel cycles utilizing reprocessing and conversion/breeding of fissile material could increase the fuel cycle contribution by an additional 5% to 10%.

⁴ At least 8 GW of (non-cogenerating) SMRs are assumed to have been built by 2030, subsequently reducing the financial risk for similar SMRs with CHP capabilities.

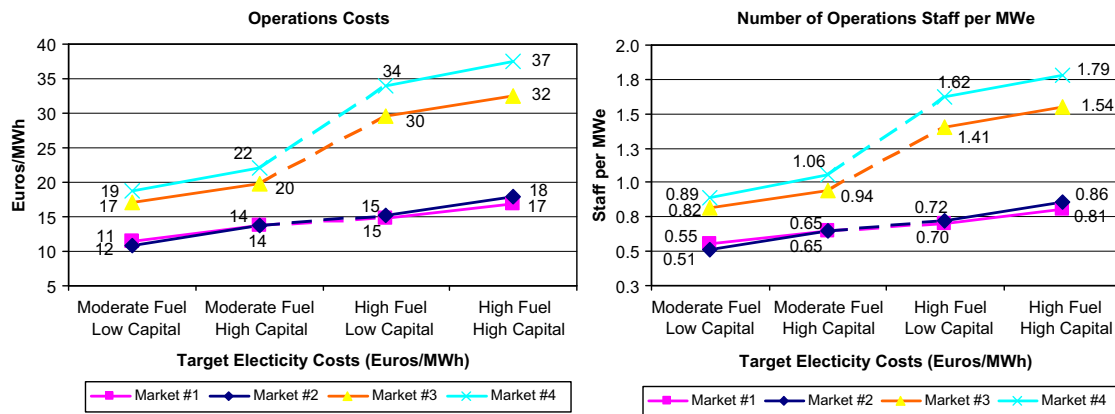


Fig. 6. Target operations costs and staffing by market sector.

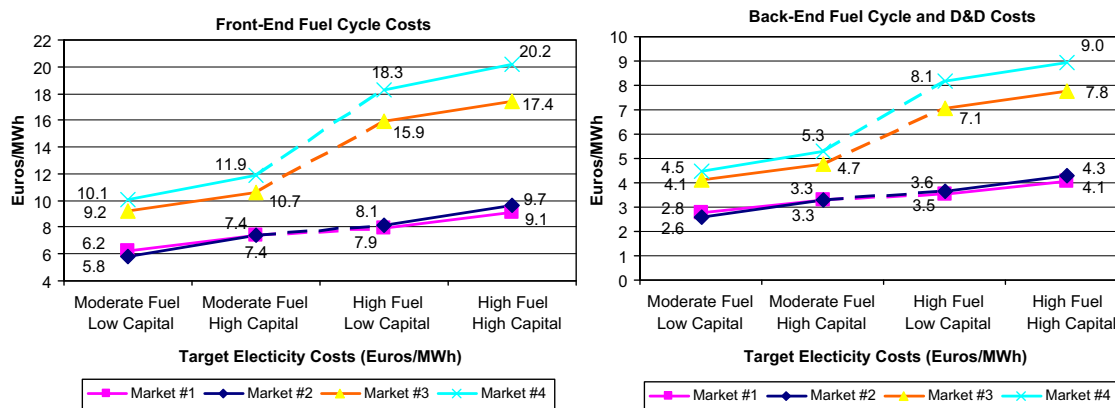


Fig. 7. Target fuel cycle front-end, back-end, and D&D costs by markets sector.

each market, four data points were analyzed (i.e., bottom and top of the moderate fossil fuel price, bottom and top of the high fossil fuel price) as previously described in Fig. 3. In Fig. 5, the reference ranges defined on the x-axis represent the range of target overnight capital and all-in capital costs for each of the markets. For example, the allowable overnight capital costs (in terms of MW electric equivalent costs) for Market #3 ranging from lowest to highest: 6980 €/kWe (moderate fuel-low carbon) to 8083 €/kWe (moderate fuel-high carbon); and 12,050 €/kWe (high fuel-low carbon) to 13,226 €/kWe (high fuel-high carbon). Recall that the high and moderate fuel cost ranges were based on the second Strategic EU Energy Review data for the four markets that were described in Section 1.

In Fig. 5, the target capital costs are given without finance charges (overnight capital costs) and with finance costs⁵ (all-in capital costs). As an example, for a small reactor-CHP to compete against fossil energy technologies (coal or gas) with moderate fuel costs and low-high capital costs, its overnight capital cost would need to be in the range of 5000–7500 €/kWe.

In Fig. 6, the allowable target operations costs (€/MWh) and staffing numbers (staff per MWe) are estimated. For example, a 200 MWe equivalent combined cycle equivalent small reactor would have between 102 (i.e., 0.51×200) and 358 (i.e., 1.79×200) operations staff. The large differences in staff are a

direct result from the large difference between target market costs for coal (Markets 1 and 2) and gas (Markets 3 and 4) as shown in Fig. 3.

Fig. 7 provides the allowable fuel cycle front-end and back-end/D&D costs (in terms of €/MWh). The total SMR-CHP fuel cycle cost would range from ~8 to 29 €/MWh, which again reflects the large differences between coal and gas markets.

These cost breakdowns can provide reactor developers and analysts with an understanding of the limits for each of the major cost components (capital, operations, and fuel cycle) to successfully compete in future cogeneration markets. The costs for these small cogenerating reactors would be substantially higher than for a large nuclear power plant. The International Energy Agency (IEA) in 2009 reported that the median costs for a typical 1400 MWe light water reactor are \$3676/kWe (2789 €/kWe) for overnight capital, \$14.74/MWh (10.0 €/MWh) for operations and maintenance, \$7/MWh (4.76 €/MWh) for front-end cycle costs and \$2.33/MWh (1.58 €/MWh) for back-end costs (IEA, 2009). Reactor vendors may find this information useful in setting design-to-cost goals for their systems. The preference would be to develop small reactor-CHP that can successfully compete within the moderate fuel range where there is the greatest market opportunity. However, achieving small reactor costs within the competitive high fuel cost range may also be viable for markets that are vulnerable to fossil fuel cost fluctuations and future CO₂ costs. Further insights on the costs were derived through a sensitivity analysis of the modeling parameters which is provided in Section 5.

⁵ A discount rate of 7.5% was assumed in these calculations, based on moderate financial risk.

6. Target cost sensitivity analysis

6.1. Sensitivity of operational, financial, and technology performance parameters

In the calculation of the cost targets in Section 4, assumptions were made regarding anticipated reactor performance, financing, construction times, and reactor efficiencies. To test the importance of these parameters on achieving the cost targets, a sensitivity analysis was performed. The baseline values used to generate the target costs and the “off-target” moderate and high values used in the sensitivity analysis are shown in Table 5. These values were based on engineering judgment and historical experience for reactor capacity factors, financing rates for nuclear, construction periods, and plausible efficiency rates. The exact values of the performance input parameters are not so important, but their impacts to the small reactor-CHP costs are important.

6.2. Sensitivity due to target cost uncertainty

This analysis has produced a breakdown of SMR costs that would need to be achieved by reactor vendors in order to compete in the targeted markets. The cost breakdown can be used as a general guide, however keeping in mind that higher costs in one area could be compensated for in another area. To better understand the relative importance of each of the cost parameters, a sensitivity analysis was performed as shown in Table 6.

The off-target values were derived from U.S. DOE Advanced Fuel Cycle Initiative (AFCI) and IAEA SMR cost and fuel cycle studies. Overnight capital costs were increased by a factor of 1.5 and 2.0 for the small reactor-CHP overnight capital costs based on the cost range for the SMR (Module R4) in the AFCI report (Shropshire et al., 2009b). Given the large potential uncertainties in small reactor HTR fuel (uranium, conversion, enrichment, and fuel fabrication) and disposition costs (depleted U disposition, fuel storage, and waste disposal) a wide range of costs (150–350% for fuel and 125–250% for disposition) were investigated based on the ranges in the AFCI report (ibid). For low calculated target staffing levels (i.e., less than 0.9 staff/MWe), the estimates were increased to 0.9 and 1.5 staff/MWe (IAEA, 2001) for the moderate and high off-target sensitivity analysis, respectively.

Table 5
Performance input parameter values for the baseline and off-target conditions.

Performance parameters	Units	Target market (baseline #'s)	Off-target (moderate)	Off-target (high)
Reactor capacity factor	%	90	85	75
Discount rate	%/Year	7.5	10	12.5
Construction period	Years	4	5	6
Efficiency (eq. combined cycle)	%	38.7%	35.0%	31.0%

Table 6
Cost input parameter values for the baseline and off-target conditions.

Cost parameters	Units	Target market (baseline #'s)	Off-target (moderate)	Off-target (high)
Overnight capital cost	€/kWe	As calculated	× 1.5	× 2.0
Staff per MWe	# Staff/MWe	As calculated	Increased to 0.9	Increased to 1.0
Fuel cost	€/MWh	As calculated	× 1.50	× 3.5
Disposition cost	€/MWh	As calculated	× 1.25	× 2.5

6.3. Sensitivity analysis target chart

The uncertainty analysis was performed on the performance and cost parameters using the moderate and high (off-target) values for each of the target markets. The results of the sensitivity analysis on the four markets were similar, so for the sake of brevity only the results for Market #3 are displayed in the target chart in Fig. 8.

6.4. Discussion of the sensitivity analysis results.

As shown in the target chart for Market #3 (centered at 95 €/MWh, i.e., low end of the natural gas cost range without CCS), most of the off-target hits are within the center green ring (less than 110 €/MWh, i.e., top of the moderate-fuel cost range for natural gas without CCS) corresponding to the range shown in Fig. 3 for CCGT CHP. Outside this ring are hits from overnight capital and discount rate (moderate and high values), fuel cost, reactor capacity factor, and efficiency (high values only). Although these hits drift from the center of the target they fall below the high fuel cost range shown between the black ring at 160 €/MWh (bottom of the high fuel cost range) and the orange ring at 180 €/MWh (top of the high fuel cost range). The high off-target value (× 2.0) for overnight capital (~160 €/MWh) brings the costs closest to the non-competitive range for the high fuel price (outer ring). Future analysis shows that capital costs exceeding 2.6 times the “target cost” estimates would result in an overall non-competitive cost position for Market #3, assuming that all other parameters hit their target costs. This outer bound limit for the overnight capital cost varies depending on the market. For Market #4 the factor is even higher at 2.9. However for Markets #1 and #2 the factor decreases to 1.4 and 2.0, respectively, thus indicating tighter market constraints. Discount rates, although out of the control of the reactor developer, can also significantly add to the costs and would compound the effect from higher capital costs. Fuel costs, reactor capacity, and efficiency at their highest values can also influence the competitiveness. When more than one parameter misses the mark, the overage costs are additive, for example [95 €/MWh (target) + 10 €/MWh (added fuel) + 50 €/MWh (added capital) = 155 €/MWh].

There is no significant difference between the cost sensitivities for small reactor-CHP plants and for larger NPPs. The impact of capital costs and financing rates is largely dominant but somewhat less for small reactor-CHP due to their reduced fraction of total costs (see Table 2). Containing costs from the fuel cycle and operations will be more important for SMRs than for LWR (but only because you assume a large uncertainty for SMR fuel).

Another factor to be considered when installing nuclear CHP is that a back-up for downtime is required. The back-up could be a fossil-fired boiler. Since these are site specific issues their economic impacts need to be considered on a case-by-case basis, however they have a non-negligible impact on the economics. In fact, nuclear cogeneration should be installed with priority where there is already fossil cogeneration available. Also, the substitution of large coal-fired CHP with nuclear CHP could be an ecologic

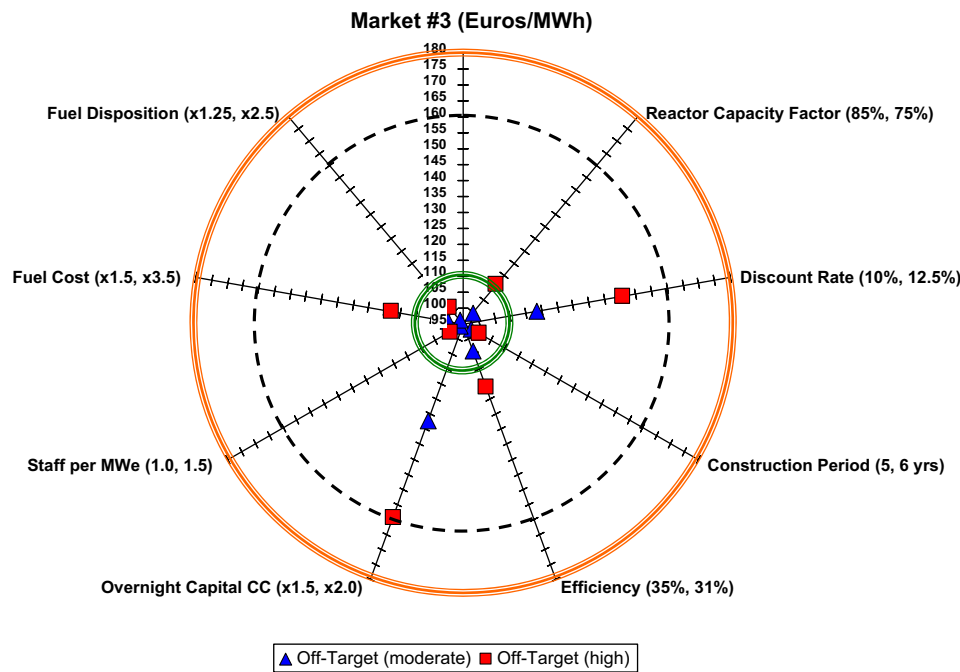


Fig. 8. Results of the sensitivity analysis on the performance and cost variables.

and economic priority because the CO₂ curbing effect is twice as high as through replacement of gas-fired CHP. A somewhat higher price for nuclear CHP could be accepted because it would make CCS of the coal-fired system superfluous.

7. Discussion

Insights on the cost targets are useful, but the practical means for achieving these competitive cost targets are most important. The competitiveness of SMRs used in electricity applications were reported by Shropshire (2011) to be based on how well (1) they are matched to their market niche, (2) their financial risks are managed, (3) innovation is applied to the reactor and fuel design, (4) the economies-of-scale effect is reversed, how economy of replication can kick in, (5) reactors are deployed, and (6) operational efficiencies are maintained for the life of the plant. More importantly, SMRs must incorporate improved safety and non-proliferation controls to be licensed for use. These same conditions are applicable to cogeneration applications, which have even further challenges that are discussed below.

Whereas nuclear power for electricity production has won a significant place in its market, nuclear heat production and cogeneration did not come past small scale applications yet. Apparently, some hurdles still have to be overcome.

A first hurdle is the low fossil fuel prices. As long as the prices for fossil fuels, mainly natural gas, remain as low as they have been in the past few decades (and the exploitation of shale gas already has lowered the US gas price), there is no economic incentive to switch to alternatives. This may change with serious CO₂ taxing, the obligation to apply CCS or with the strongly increasing global demand.

Even with high costs for competing alternative fuels, CHP must also be able to compete against the alternative of producing electricity and heat separately. In a CHP some electricity efficiency is given up for the benefit of heat production. The income from selling heat should at least compensate the income lost from less electricity generation.

A second hurdle is the political climate and (non-)existence of national energy strategies which create the required long-term stability for companies to freeze large amounts of money in strategic long-term investments. The political climate is directly coupled to public perception—public attitudes towards nuclear energy are hesitant, which is a barrier that needs to be overcome for nuclear cogeneration to succeed.

A third hurdle is the technological readiness level of the available nuclear technologies. Nuclear CHP plants are currently in the development or prototype stage. Platforms like the European Nuclear Cogeneration Industrial Initiative are envisaging the demonstration of nuclear cogeneration at a relevant scale. Similar initiatives already exist in the US, South-Korea, China, and Japan.

A fourth hurdle is the limitation in temperature of current nuclear technology compared to fossil-fueled CHP—today the heat production in nuclear cogeneration is limited to 550 °C. To deliver heat at higher temperatures new materials need to be developed. Since higher temperatures are more valuable, this is in principle desirable for the future. However, the heat market up to 550 °C is already so big, that this hurdle can be considered little relevant before long.

Finally, the safety requirements of nuclear CHP plants need to be defined and worked out. Needless to say that for a nuclear cogeneration plant to be located next to chemical industries, the nuclear reactor, end-user installation, and common interface have to be very safe. But how safe is 'very safe'? It needs to be clarified with licensing authorities whether and how nuclear CHP plants located in the vicinity of end-user industries will be subject to additional safety requirements compared to fossil-fired conventional CHP plants and compared to nuclear electricity generating plants. It will also need to be clarified whether and how smaller more forgiving reactor designs like the modular high temperature reactor will be credited for their passive inherent safety features with regard to licensing requirements. The safety issue is directly related to the siting issue: on one hand nuclear power plants need a certain safety area around the plant, which depend on different factors, e.g. plant size and population density. On the other hand, it is most attractive to place the cogeneration plant as close as

possible to the heat demand to reduce heat losses. Heat, typically steam, can only be transported on shorter distances. For industrial purposes the limit is usually a couple of kilometers. For longer distances, heat transport in the form of chemical energy can be envisaged. When the heat demand is for low temperature, larger mass flows heat can be transported longer distances, i.e., up to 100 km.

8. Future studies

There will be an ongoing need for protection from nuclear proliferation if there are to be a large number of SMRs scattered over broad geographic areas, and at locations not previously considered for current generation nuclear plants requiring larger exclusion zones. Possible options exist for these new reactors to include features of enhanced proliferation resistance and increased robustness of barriers for sabotage protection. For example, the reactors could be designed to operate without on-site refueling or will have long periods between refueling using well-contained fuel cassettes that would impede clandestine diversion of nuclear fuel material. Future studies are needed to minimize the risk of proliferation to acceptable security levels.

It is important to study further the interconnection between the nuclear cogeneration plant and the heat users. A safety approach for CHP must be defined, in order to clarify the safety requirements as mentioned in the previous paragraph. It is important to complete the picture of design and licensing requirements for investors and end-users, without leaving any open ends.

A study of institutional resistances against using nuclear cogeneration could show how obstacles can be avoided so that implementation can be achieved. There is much resistance, inertia, and debate about new technologies and especially in nuclear cogeneration.

Future studies can evaluate how a hybrid-nuclear cogenerating reactor capable of shifting between electricity and heat production could be used to balance the electricity supplies when a large share of electricity is produced by variable renewable energy. Potentially, a small nuclear cogeneration plant could shift between heat and electricity production. During periods of high wind power generation the nuclear cogenerating plant could shift energy production to heat processes (e.g., biomass drying and torrefaction) and energy storage (e.g., adiabatic compressed air storage). At low wind conditions the plant would switch to pure electricity production and stored energy could be converted to electricity. A business model might be developed, in which an energy production company owns multiple nuclear CHP plants at different locations, sells the heat and power generated to the users at these locations, delivers excess power to the grid if profitable, and at the same time complements the energy production from solar and wind farms.

9. Conclusion

Small nuclear concepts have been considered for use in electricity applications, but they also may be suited to support process heat markets. The small cogenerating nuclear reactors align well with the capacity requirements of process industries. Most reactor cogenerating concepts are still in the design stage and detailed cost estimates are not publicly available. In this study, target costs were derived based on competing technology energy costs in a range of markets. The actual competitiveness of nuclear reactors in these markets is yet to be demonstrated, but key cost uncertainties include the overnight capital and the cost

of capital. Cogenerating reactors may be competitive against coal-CHP and gas-CHP, particularly if carbon constraints and fuel uncertainties continue to drive up costs in these markets in the future. Small reactors have the added value of no carbon emissions from operations and low impact of fuel cost increases. Technical evaluations such as EUROPAIRS and the ARCHER project will help to determine how a nuclear cogeneration plant can switch between heat and electricity production in order to balance the variability from renewables on the electricity grid. There is a further need to assess the commercial viability of these strategies and understand the potential institutional resistances against using nuclear cogeneration so that obstacles to implementation can be avoided. The most convincing argument for potentially interested end-users is probably the successful demonstration of nuclear cogeneration technology at a relevant production scale.

Acknowledgment

This work has been carried out within the multi-annual work programme of the “Assessment of Energy Technologies and Systems” (ASSETS) Action of the European Commissions’ Joint Research Centre.

References

- AGFW, 2005. Perspektiven der Fernwärme und Kraft-Wärme-Kopplung – Ergebnisse und Schlussfolgerungen aus der AGFW-Studie “Pluralistische Wärmeversorgung”. Frankfurt am Main.
- Bredimas, A., 2010. Market Study: Energy Usage in European Heat Intensive Industries. LGI Consulting Report for EUROPAIRS Project (December) <<http://www.europairs.eu/>> (accessed 23.08.11).
- Candeli, R., Garribba, S.F., Hansen, U., Lefevre, J.C., Leuchs, D., Schon, R., Vivante, C., 1988. Market potential of small and medium-size nuclear reactors as combined heat and power plants in Europe. Nuclear Engineering and Design 0029-5493/109 (1–2), 373–379. doi:10.1016/0029-5493(88)90184-7. (September–October).
- CASES, 2008. Framework Programme 6 Project No. 518294 SES6. Deliverable 4.1—Private Costs of Electricity and Heat Generation.
- ETSAP, 2010a. Technology Brief E14. CO₂ Capture and Storage.
- ETSAP, 2010b. Technology Brief I01. Industrial Combustion Boilers.
- EUROHEATCOOL, 2006. Workpackage 1. The European Heat Market—Final Report.
- EUROPAIRS, 2009. FP7 End User Requirement for Process Heat Applications With Innovative Reactors for Sustainable Energy Supply (EUROPAIRS). <http://cordis.europa.eu/fetch?CALLER=FP7_PROJ_EN&ACTION=D&DOC=1&CAT=PROJ&RCN=94416> (last accessed 10.12.10).
- European Commission (EC), 2003. Directive 2002/91/EC. On the Energy Performance of Buildings.
- European Commission (EC), 2004. Directive 2004/8/EC. Promotion of Cogeneration Based on a Useful Heat Demand in the Internal Energy Market and Amending Directive 92/42/EEC.
- European Commission (EC), 2006. Directive 2006/32/EC. On Energy End-Use Efficiency and Energy Services and Repealing Council Directive 93/76/EEC.
- European Commission (EC), 2007. COM(2007) 723 Final. A European Strategic Energy Technology Plan (SET-Plan)—Towards a Low Carbon Future.
- European Commission (EC), 2008. Commission Staff Working Document Accompanying the Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. Second Strategic Energy Review. An EU Energy Security and Solidarity Action Plan, Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating, and Transport, SEC, vol. 2872 (November 13).
- Generation IV (Gen IV) Economic Modeling Working Group, 2007. Cost Estimating Guidelines for Generation IV Nuclear Energy Systems. Rev. 4.2. GIF/EMWG/2007/004 (September 26).
- International atomic energy agency (IAEA), 2001. Staffing Requirements for Future Small and Medium Reactors (SMRs) Based on Operating Experience and Projections. IAEA-TECDOC-1193 (January).
- International Energy Agency (IEA), 2009. Projected Costs of Generating Electricity 2010 Edition. IEA/SLT(2009)12 (December).
- MacDonald, M., 2010. UK Electricity Generation Costs Update (June). <<http://www.decc.gov.uk/assets/decc/Statistics/Projections/71-uk-electricity-generation-costs-update-.pdf>> (last accessed 10.12.10).
- NERA Economic Consulting, 2005. Paper 4. The Economics of Nuclear Power. A Report to the Sustainable Development Commission, Science and Technology Policy Research, University of Sussex (22 November).

- OECD/NEA, 1991. Small and Medium Reactors Status and Prospects. Report by an Expert Group.
- OECD/NEA, 2006. Advanced Nuclear Fuel Cycles and Radioactive Waste Management. NEA No. 5990. OCED.
- OPET, 2007. Combined Heat and Power Plant AT Dairygold Cooperative—Mitchelstown. OPET/Irish Energy Centre. Good Practice Case Study 3. <<http://www.sei.ie/uploadedfiles/InfoCentre/casestudy3dairygold.pdf>> (accessed 21.07.11).
- Shropshire, D.E., Williams, K.A., Hoffman, E.A., Smith, J.D., Hebditch, D.J., Jacobson, J.J., Morton, J.D., Phillips, A.M., Taylor, J.P., 2009a. Advanced Fuel Cycle Economic Analysis of Symbiotic Light-Water Reactor and Fast Burner Reactor Systems. INL/EXT-09-15254 (January).
- Shropshire, D.E., Williams, K.A., Smith, J.D., Dixon, B.W., Dunzik-Gougar, M., Adams, R.D., Gombert, D., Carter, J.T., Schneider, E., Hebditch, D., 2009b. Advanced Fuel Cycle Cost Basis. INL/EXT-07-12107 (December).
- Shropshire, D., 2011. Economic Viability of Small to Medium-Sized Reactors Deployed in Future European Energy Markets. Progress in Nuclear Energy. doi:10.1016/j.pnuene.2010.12.004.
- U.S. Department of Energy (US DOE), 2001. Report to Congress on Small Modular Nuclear Reactors (May).
- van Heek, A., 2004. ACACIA: a small scale power plant for near term deployment in new markets. Nuclear Engineering and Design 234 (1–3), 71–86. (December).
- Zhang, Z., Sun, Y., 2007. Economic potential of modular reactor nuclear power plants based on the Chinese HTR-PM project. Nuclear Engineering and Design 237 (23), 2265–2274. (December).
- Zhang, Z., Wu, Z., Wang, D., Xu, Y., Sun, Y., Li, F., Dong, Y., 2009. Current status and technical description of Chinese $2 \times 250 \text{ MW}_{\text{th}}$ HTR-PM demonstration plant. Nuclear Engineering and Design 239 (7), 1212–1219.